Chapter 8 Well Activity: Drilling

8. Well Drilling

Please Note:

This manual is written as a whole and provided to industry in sections to allow permit holders to access activity chapters. It is prudent of the permit holder to review the manual in its entirety and be aware of the content in other sections of the manual.

8.1 Drilling Reporting

8.1.1 Drilling Status Updates

The status update informs the Regulator of the drilling status of a well (spud, drilling suspended, drilling resumed and rig release), and is submitted through the Regulator's eSubmission portal. The information required in the portal depends on the drilling status change. Status updates must be provided within one business day of a change in drilling status.

For drilling re-entry wells, the supplemental Engineering Data Form accompanying the well permit or well permit amendment will specify what will be deemed as the spud date. Refer to the Re-entries Section of this manual for additional information.

Drilling suspended means a drilling rig has been released, but the drilling of the well is not complete, and the permit holder intends to resume drilling within one year of rig release.
Examples of this situation include:

- Surface hole rig.
- Switch out rigs for horizontal underbalanced drill.

- Release drilling rig, switch to service rig to penetrate play with air (also considered a drilling operation).
- Drilling ceases due to breakup and will resume when access is restored.
- For a short suspension of drilling operations (for instance, seasonal shutdowns), do not report as drilling suspended. On the Summary Report of Drilling Operations explain the reason for the short suspension (for example: seasonal/holiday shutdown for five days).

Drilling resumed means drilling has resumed after a drilling suspension. The drilling resumed date is usually when the bit commences making new hole.

Rig released means the drilling of the well is complete.

8.1.2 Incident Reporting

Incidents may include, but not limited to; spills, gas release, fire/explosion, kicks of certain level, vandalism or threats and major structural failures. Refer to section 8.2.3 for more information on kick reporting.

All incidents must be reported following the Regulator's Incident Reporting Instructions and Guidelines document.

8.1.3 Kick Reporting

All kicks must be reported to the Regulator through the eSubmission portal within 24 hours of the occurrence. A follow-up update may be required, depending on the well control situation.

If a kick meets any one of the following criteria, it must be reported as an incident (refer to section 8.1.2 for incident reporting):

- Pit gain of 3 m^3 or greater.
- Casing pressure 85 per cent of maximum allowed casing pressure.
- 50 per cent or more out of hole when kicked.
- Well taking fluid (lost circulation).
- Associated spill.
- General situation deterioration, (for example: leaks, equipment failure, unable to circulate, etc.).

Deterioration of the well control situation should be reported to a Regulator Drilling Engineer. If a Regulator Drilling Engineer is unavailable or if after hours, call the Regulator 24-hour Incident Reporting Line at 1-800-663-3456.

8.1.4 Lost Circulation Reporting

When the lost volume is equal to or greater than 5 m^3 for oil based mud or 10m^3 for water based mud, the lost circulation must be reported through the Regulator's eSubmission portal before rig release.

8.1.5 Hole Problem Reporting

For fish in hole, sloughing hole, cementing problem, well control issues or other hole problems where the Regulator's assistance is required, contact a Regulator Drilling Engineer. If a Regulator Drilling Engineer is unavailable or if after hours, call the Regulator 24-hour Incident Reporting Line at 1-800-663-3456.

8.2 Well Drilling Data Requirements

8.2.1 Summary Report of Drilling Operations

The summary report of drilling operations must be submitted to the Regulator through the eSubmission portal within four business days of rig release or drilling suspended. This includes when the rig is moved or shut down for a period of time, but excludes shutdowns for rig repairs or seasonal holidays.

The Summary Report of Drilling Operations must be completely and accurately filled out. As shown in Table 8A, a summary of formation tops and logs run must accompany the online submission of the Summary Report.

This summary must include the following:

- A list of formation tops as picked from the logs. If no open hole logs are run, formation tops may be selected from the measurement while drilling gamma ray (MWD-Gr) log. If there is no MWD-Gr log, formation tops may be selected based on drill cuttings samples.
- Measured depth (MD) and true vertical depth (TVD) must be provided if the well is directional or horizontal.
- List of logs run (including MWD-Gr) with the following information:
    - Log type run (include MWD-Gr if run). The log type must be written out in full - for instance, borehole compensated sonic, not BHC.

- Run number.
- Last date run for each run number (finished date).
- Intervals logged (that is, top depth and bottom depth) for each log including measured depth and true vertical depth, as applicable.
- Bottom hole temperature (BHT) must be included with the written list of logs run.

Table 8A Formatting for Summary Report of Drilling Operations

Log Type (Name)	Run #	Run End Date	Top Depth (MD)	Bottom Depth (MD)	Top Depth (TVD)	Bottom Depth (TVD)	Bottom Hole Temp (BHT)

Submit the full name of the log, no abbreviations.

For each log, one line of information must be entered.

For wells that have experienced drilling problems not evident from the Summary Report of Drilling Operations, provide a brief point summary in the comments section to explain the problems. For example:

- Drilled to 800 metres, lost fish in hole.
- Fish top at 600 metres, fish bottom at 750 metres.
- Brief description of fish.
- Address issue of potential interzonal communication (if applicable).
- Set plug #1.
- Kicked off plug at depth of 1,215 metres to drill around fish.

For drilling re-entries, provide a brief point summary (in the comments section) of the operations performed if not evident from the Summary Report of Drilling Operations.

For example:

For a basic squeeze of existing perforations, bridge plug set and mill of window in casing to drill horizontally out of cased vertical well.

- Started drilling on surface three metre abandonment plug at 0800 hr 2007-06-15.
- Cement squeezed existing perforations and pressure tested same.
- Set bridge plug at 1,800 metres and whipstock and commenced cutting window.

Refer to the Well Data Submission Requirements Manual for file naming and submission requirements.

8.2.2 Directional Survey

A wellbore directional survey is required if:

- Well is horizontally or directionally drilled.
- Surface location of well is outside target area.
- Surface location of well is within the target area but closer to the target boundary than measured depth multiplied by two per cent.

Example (for a well with a 250 meters (m) gas target setback):

Gas well total measured depth = 2,200.0 m.

2,200.0 m X 2% = 44.0 m.

44.0 m + 250.0 m = 294.0 m.

Therefore, if the well surface location is closer than 294 m to the spacing border, a directional survey must be run.

Directional surveys must include:

- Actual surface coordinates of the wellhead.
- Last point on the directional survey must be the total measured depth (TMD) of the well bore. This allows the Regulator to link the directional survey with the correct drilling event.
- Cross-section and plan view graphical plots must be included within the PDF file if available.

Directional surveys should be saved and submitted in both TXT and PDF format. The Regulator's Directional Survey File Format Guide provides detailed information regarding the submission of directional survey data and the As-Drilled Survey Plan.

Deviation Surveys

Deviation surveys must be made during drilling at intervals not exceeding 150m in depth, unless there are significant wellbore stability problems, in which case a survey may be omitted.

8.2.3 Drillstem Testing

A pressure chart and report containing complete details on fluid recoveries and other pertinent facts for each drillstem test or wire line test taken on a well must be submitted to the Regulator within 30 days using eSubmission portal within 30 days of the date on which the test was made.

Useful references for drillstem testing include:

- Worksafe BC's Drillstem Testing Safety Guidelines for drilling and service rigs. Covers safe work guidelines, minimum health and operating standards and personnel qualifications.
- The ESC's IRP Volume #4: Well Testing and Fluid Handling.

8.2.4 Drill Cutting Samples and Core Samples

Drill cutting samples are required at intervals of five metres, beginning at 50 metres measured depth above the shallowest potential reservoir zone and continuing to the total depth of the well.

In accordance with Section 29 of the Drilling and Production Regulation, well samples and cores must be collected during drilling operations and submitted to the Regulator within 14 days of rig release. Refer to the Well Data Submission Requirements Manual for further information on related submission process and requirements.

8.2.5 Well Logging

A gamma ray log is required from the ground surface to the total depth of the well.

A neutron log is required from 25 metres below ground level to the base of the surface casing.

Resistivity and porosity logs are required from the base of the surface casing to the total depth of the well.

Wellbores may penetrate up to 20 metres below the lowest objective formation in order to fully log the objective formation.

If a well is part of a multi well pad, only one well needs to have all the above mentioned logging conducted, however, all wells must have a gamma ray log taken from the base of the surface casing to the total depth. This applies for the unconventional zones listed in Schedule 2 of the Drilling and Production Regulation.

8.2.6 Wellsite Geology Report

Well Site Geology Report

Submits a well site geology report through the eSubmission portal portal within 60 days of rig release. Refer to the Regulator's Well Data Submission Requirements Manual for more information on submission of wellsite geology reports.

8.2.7 Logging and Sample Waiver

Requests for logging and sample waivers should be made during business hours to the Regulator's Petroleum Geology, Resource Stewardship & Major Projects. The request should be submitted to a geologist by email, clearly stating the request and the reason for the request (for example, hole conditions). Refer to the Regulator phone list on the website and Petroleum Geology, Resource Stewardship and Major Projects for Contact information. After business hours, the Regulator's 24-hour phone line in Fort St. John is 250-794-5200.

8.2.8 Flaring During Drilling

If flaring during drilling operations is necessary, note the following:

- A Notice of Flare must be submitted using the eSubmission Portal for underbalanced drilling. The total flared volume must be reported via Petrinex, in accordance with the usual production volume reporting timeline. In addition, a Well Deliverability Test Report must be submitted through the eSubmission Portal within 60 days.
- For other operations (drillstem testing, managed pressure drilling, kick flaring) advance notification is not required and flared volumes must be reported on the Summary Report of Drilling Operations.
- Estimation is permitted for operations such as kick flaring where accurate measurement of flared volumes is not possible.

To discharge air contaminants pursuant to Section 6(1)(d) of the Oil and Gas Waste Regulation, the permit holder must, at least 15 days prior to commencement of well test flare or incineration of sour gas containing ≥ 5 mole per cent H_2S, in accordance with Section 8 of that regulation, submit dispersion modelling and details of the well test to the satisfaction of the Regulator. Submissions must be provided to Waste.Management@bc-er.ca.

8.2.9 As Drilled Wellsite Survey Plan

Section 35(1) of the Drilling and Production Regulation requires the submission of an As-Drilled Survey Plan within 14 days of rig release. The survey plan must be in its original size from the Surveyor (for example, 22" x 34") as a PDF, and show and clearly identify the following information:

- ·Surface and bottom hole location of all drilling events associated with the well
- ·Northing and Easting coordinates, determined using NAD 83
- ·North and East offsets to the nearest corner of the spacing unit, and the reference corner

8.2.10 Well Drilling Site Clean Up (Waste Management)

Permit holders must clean up the well drilling site and restore the surface upon drilling completion and submit a Well Site Clean Up Form and Drilling Waste Report where applicable and detailed in this section. Refer to the Drilling Waste Management Chapter of the oil and gas handbook for more information on drilling waste management.

Well Site Clean Up Form

A Well Site Cleanup Form is required after a well as been drilled to report and inform the Regulator of well site and waste management activities.

A Well Site Clean Up Form should include the well name and number, well site sketch drawings and if available, photographs of disturbed areas. Detailed requirements are included on the form. The Regulator's Well Site Clean Up Form is available as a word document, downloaded online from the Regulator's website. Once completed, the form is mailed to the Regulator address as indicated on the form within 60 days of rig release.

Drilling Waste Disposal Report

The Drilling Waste Disposal Summary form should include the permit number, sketches, laboratory results and field analysis and, if available, photographs. Detailed requirements are included in the form. The Drilling Waste Disposal Summary form is submitted using the Regulator's eSubmission portal within 90 days of the closing of any earthen pit used to store drilling waste.

8.3 Blowout Prevention: Practices and Procedures

The following section outlines blowout prevention standards that a permit holder should follow to comply with the requirements of Part 4, Division 2 of the Drilling and Production Regulation. It is the responsibility of the permit holder to ensure that blowout prevention equipment and procedures are adequate.

A permit holder may use alternate blowout prevention equipment and techniques if they can demonstrate by means of a detailed engineering analysis that the alternate equipment or techniques are adequate as required by Section 16(1) of the Drilling and Production Regulation. This engineering analysis should be submitted as part of the well permit application.

Recommended and industry accepted blowout prevention (BOP) guidelines are included in this section. BOP stack schematics are in Appendix A of this manual.

If an operation is not covered in these guidelines, refer to the applicable industry recommended practices (for example, Energy Safe Canada (ESC) IRPs at www.energysafetycanada.com). Exercise caution when drilling surface holes.

It is prudent to utilize divertors in areas where shallow gas has been encountered or in wildcat areas (areas where little is known with certainty about the subsurface geology) as further explained in Appendix C of this manual.

8.3.1 Blowout Prevention Classifications

Blowout prevention equipment is classified as follows:

1. Class A: to be used from the depth of the surface casing to 1,800 metres true vertical depth.
2. Class B: to be used from a depth of 1,800 metres to 3,000 metres true vertical depth.
3. Class C: to be used from a depth of 3,000 metres to 5,500 metres true vertical depth.
4. Class D: to be used from a depth of 5,500 metres true vertical depth and greater.

8.3.2 Blowout Prevention Pressure Ratings

The minimum pressure rating of blowout prevention equipment must be:

1. 14,000 kPa for Class A equipment.
2. 21,000 kPa for Class B equipment.
3. 34,000 kPa for Class C equipment.
4. 70,000 kPa for Class D equipment.

8.3.3 Other Blowout Prevention Stipulations

When a well is being drilled, blowout prevention equipment must, at all times:

1. Consist of a minimum of one annular preventer and two or more ram preventers; the ram preventers are to be comprised of a blank ram and one or more rams to close off around drill pipe, tubing or casing being used in the well.
2. Be connected to a casing bowl that is equipped with:
3. An upper flange that is an integral part of the casing bowl.
4. For blowout prevention Class A and B, at least one threaded, flanged or studded side outlet with one valve.
5. For blowout prevention Class C and D, two flanged or studded side outlets with two valves.
6. Include steel lines or adequate high pressure hoses connected to the blowout preventer assembly, one or more for bleeding off pressure and one or more for killing the well.
7. Consist of components having a working pressure equal to that of the blowout preventers, except that part of the bleed-off line or lines located downstream from the last control valve on the choke manifold.
8. Have the valve hand wheel assembly in place and securely attached to the valve stem on all valves in the blowout prevention system.
9. Be maintained so that its operation will not be impaired by adverse weather conditions.
10. Hammer unions should not be used in the manifold shack or under the substructure on the primary well control system but can be used in UBD/MPD pressure/flow control system providing the hammer union end connection is welded to the pipe.
11. Conform to the specifications set out in Appendix B.

8.3.4 Blowout Prevention Controls

If hydraulically operated blowout preventers are installed, a clearly marked operating control indicating direction of closure for the annular blowout preventer must be located at least 15 metres from the well.

The control valve regulating the closure of the annular preventer must be free of any valve locking device.

All manual controls for the locking of manual ram type blowout preventers must be installed or readily accessible.

If ram type blowout preventers are used at a cased well, the controls must be attached and be at least five metres from the well.

All blowout preventers must be hydraulically operated and connected to an accumulator system.

8.3.5 Blowout Prevention Ancillary Equipment

Bleed Off Lines

The bleed off lines referred to above must be:

1. A minimum nominal 76 millimetre diameter of uniform bore.
2. Connected only by welded neck flanges that are perpendicular to the line to which they are attached.
3. Equipped with a gauge connection where well pressures may be measured.
4. Connected to a choke manifold and a mud tank through a mud gas separator.
5. Securely held down and terminated in a slightly downward direction into an earthen pit or flare tank, if the lines are downstream of the choke manifold.

Choke Manifold

The choke manifold referred to above must be located outside the substructure and be readily accessible with safe routes of access and egress.

The choke manifold must provide safe and protected area for the crew to work during well control operations.

The choke manifold referred to above must be designed:

1. To conform with Class A, B, C or D equipment.
2. To permit the flow to be directed through a full opening line or through either of the two lines, each containing an adjustable choke.
3. Equipped with accurate metric pressure gauges to provide drill pipe and casing pressures at the choke manifold once the surface casing is cemented in place.
4. Enclosed by a suitable housing, with adequate heat to prevent freezing.
5. Securely tied down and containing only pipe that is straight or with a 1.57 radian bends (90º) and which is constructed of flanged, studded or welded tees, blank flanged or ball plugged on fluid turns in addition to having bleed off lines.
6. Hammer unions must not be used on main flow lines in the enclosure that houses the choke manifold.

Accumulator

The accumulator system must be:

1. Installed and operated in accordance with the manufacturer's specifications.
2. Connected to the blowout preventers, with lines of equivalent working pressure to the system, and within 5 metres of the well - the lines must be of steel construction unless completely sheathed with adequate fire resistant sleeving.
3. Capable of providing, without recharging, fluid of sufficient volume and pressure to close the annular preventer, close a ram preventer, open the hydraulically operated valve and retain a pressure of 8,400 kPa on the accumulator system.
4. Recharged, within five minutes, by a pressure controlled pump capable of recovering the accumulator pressure drop resulting from closing the annular preventer, closing a ram preventer or opening the hydraulically operated valve.
5. Capable of closing any ram type preventer within 30 seconds.
6. Capable of closing the annular preventer within 60 seconds.
7. Equipped with readily accessible fittings and gauges to determine the precharge pressure of each nitrogen container.

If nitrogen cylinders are used as an emergency pressure source, sufficient usable nitrogen must be available at a minimum pressure of 8,400 kPa to fully close the annular preventer and pipe rams and open the hydraulically operated valve.

Mud Tank Fluid Volume Monitoring Systems

A mud tank fluid volume monitoring system (e.g., Pit Volume Totalizer) must be used during drilling.

The monitoring system must be sufficiently precise to detect a change of ±1 m3 in total pit volume. This typically means each active compartment must have a probe installed.

A drilling fluid level monitoring station with an alarm system must be located at or near the driller's position.

The alarm must include a visual indicator which comes on automatically whenever the alarm is shut off. The indicator must effectively alert the drillers on the floor and in the doghouse (e.g. a highly visible flashing light).

Mud tank volumes must be continuously recorded in the Electronic Drilling Recorder.

A flow line sensor is another monitoring device that can be used in conjunction with an automated mud tank volume monitoring system. The flow line flow sensor cannot be used alone as a monitoring device, but can be installed to augment the automated mud tank volume monitoring system.

Trip Tanks

The drilling mud system must be equipped with a trip tank with the capacity of 5 cubic metres to accurately measure the fluid required to fill the hole while pulling pipe from the well and the trip tank must:

- Be constructed so that the cumulative volume can be reliably and repeatedly read to an accuracy of 0.15 m^3 (150 litres) from the driller's position.
- Be tied into the mud return line.
- Be equipped so that drilling fluid can be transferred into and out of the trip tank.
- Be located in or within 10 metres of the shale shaker end of the mud tank and be readily accessible to afford visual observance of the fluid level.

A diagram of the trip tank and the trip tank volume indicator must be prominently displayed in the control centre (also known as the dog house).

The trip tank volume indicator must specify the trip tank volume and each volume graduation on the scale.

Mud-Gas Separator

Mud gas separators must:

1. Be designed to ensure personnel safety and adequate mud gas separation.
2. Be connected to a securely fastened inlet line and outlet line and the outlet line must:
    3. Be at least one size larger than the inlet line.
    4. Terminate preferably in a flare tank, but also may terminate in an earthen flare pit, at least 50 metres from the well.

Kelly Cock and Stabbing Valve

At all times when a well is being drilled:

1. A valve must be installed in the kelly assembly.
2. A full opening stabbing valve that can be connected to the drill pipe, drill collars or tubing in the well and a device capable of stopping any backflow up the drill string must be provided and must:
    1. Be equipped with removable handles to facilitate handling by two persons.
    2. Be stored in the control centre (dog house) or another satisfactory location where it is readily available for use with the valve in the open position.
    3. Have the valve closing handle attached to the valve holding stand.

Flare Tanks

Flare tanks must:

1. Be constructed of steel with walls of sufficient height to ensure liquid containment during prolonged exposure to fluid flow and extreme heat.
2. Have structural integrity.
3. Have an impingement plate to resist erosion from high-velocity gas,

liquids and solids positioned on the flare tank wall directly opposite all flare lines and diverter lines connected to the flare tank.

4. Have a minimum capacity of 8 cubic metres and be appropriately sized for the flow to avoid creating backpressure.
5. Not be covered.
6. Be positioned a minimum distance of 50 metres from the well.
7. Be equipped with a minimum 50.8 mm liquid loading steel line that is connected at all times for the purpose of drawing fluids from the tank, with the connection point of the loading line a minimum of 9 metres from the flare tank.
8. Have degasser vent lines kept separated from the liquid in the flare tank. The vent lines may be laid on the ground next to the flare tank, provided no fire hazard exists.
9. Have a minimum 10 metre setback from vegetation or other potential fire hazards.

Flare Pits

The earthen pit referred to in this document must:

1. Be excavated to a minimum depth of 2 metres.
2. Have side and back walls rising not less than 2 metres above ground level.
3. Be constructed to resist the erosion of a high pressure flow of gas or liquid.
4. Be constructed to contain any liquid.
5. Be used for emergency purposes only.

8.3.6 Testing of Blowout Prevention Equipment

Blowout equipment must be shop serviced and shop tested to its working pressure at least once every three years and test data and maintenance performed must be recorded and made available on request from a Regulator official.

Following assembly, all flow line connections that form a part of the blowout prevention system must be inspected by the rig manager and recorded in the daily report.

Prior to drilling out cement from any string of casing, each unit of the blowout prevention equipment must be pressure tested, first to a low pressure of 1,400 kPa and then to a high pressure tests described as follows:

Prior to drilling out surface casing:

1. Each ram preventer to the lesser of the maximum potential shut in pressure (if known), or required BOP Class.
2. Test the annular to the lesser of 70% of the recommended working pressure, recommended working pressure of the wellhead or the ram pressure test as per API 53 or as per the manufacturer's recommended practice.

Prior to drilling out subsequent casing string:

1. Each ram preventer to the lesser of the maximum potential shut in pressure (if known), or required BOP Class.
2. Test the annular to the lesser of 70% of the recommended working pressure or ram pressure test.

A successful pressure test is conducted for 10 minutes with pressure drop less than 10 per cent. If digital pressure test devices are used, a 5 minute test duration is acceptable under below conditions:

Low Pressure test:

1. Final pressure test must be within 90% of the required initial test pressure.
2. The 5 minute test period starts when the pressure has stabilized.
3. A maximum of 5% pressure drop over 5 minutes with a decreasing trend.

High Pressure test:

1. Final pressure test must be within 90% of the required initial test pressure.
2. The 5 minute test period starts when the pressure has stabilized.
3. A maximum of 2% pressure drop over 5 minutes with a decreasing trend.

Analog and electronic pressure gauges shall be used within the manufacturer's specified range and must be calibrated annually in accordance with OEM procedures.

Testing should be done in the direction that pressure may be held during a well control situation.

The line on the low pressure side of the valve must be open during pressure testing.

If a BOP connection is broken within the 30-day test requirement period, only that portion must be retested before drilling resumes. A complete test is still required at 30-day intervals.

Until the equipment passes these tests, further drilling must not proceed.

Casing exposed to drill pipe wear must be tested every 30 days to determine its adequacy for pressure control by either:

1. Running a casing inspection log to determine casing wear.
2. Pressure testing to a pressure not greater than 50 per cent of the burst pressure of the weakest section of the casing, or to the working pressure of the blowout preventers, whichever is less.

Each rig crew must perform a blowout prevention drill every seven days, or as conditions permit in accordance with a Canadian Association of Oilwell Drilling Contractors (CAODC) Well Control Procedure placard (available through the CAODC catalogue) or as outlined by the Energy Safe Canada (ESC) Blowout Prevention Manual.

While pulling pipe from a well, the well permit holder must ensure:

1. The hole is filled with drilling fluid at a frequency that ensures the fluid level in the well bore does not fall below a depth of 30 metres.
2. A permanent record of the drilling fluid volumes required to fill the hole is retained and submitted as part of the daily drilling reports.

While a well is being drilled or tested during drilling operations, the appropriate blowout prevention equipment must be operated daily and, if found to be defective, it must be made serviceable before operations are resumed.

The blowout prevention stack and choke manifold must be pressure tested every 30 days.

Full particulars of all tests must be reported in the daily report, and for a pressure test, the pressure applied and the duration of the test must be recorded.

8.3.7 Personnel Certification

The rig manager (tool push) and the well permit holder's representative at the well site must:

1. Be trained in blowout prevention.

2. Possess a valid Second Line Supervisor's Blowout Prevention certificate issued by Energy Safety Canada (ESC), or a Drilling Well Control Level 4 certificate issued by the International Well Control Forum (IWCF), or a Wellsharp Supervisor certificate issued by the International Association of Drilling Contractors (IADC). A copy of their qualifications must be made available to an official on request.

The driller must:

1. Be trained in blowout prevention.
2. Possess a valid First Line or Second line Supervisor's Blowout Prevention certificate issued by ESC, or a Drilling Well Control Level 3 or Level 4 certificate issued by IWCF, or a Wellsharp Driller or Wellsharp Supervisor certificate issued by IADC.

The CAODC placard or the well permit holder's Well Control Procedures placard must be legible and prominently displayed in the control centre (dog house) at all times.

8.3.8 Blowout Prevention Procedures

The rig crew must have an adequate understanding of and be capable of operating the blowout prevention equipment and the contractor or rig crew must:

1. When requested by a Regulator official, test the operation and effectiveness of the blowout prevention equipment in accordance with the CAODC issued Well Control Procedure placard or the Energy Safe Canada (ESC) Blowout Prevention Manual.
2. Record drills performed in the daily drilling reports.

8.3.9 Special Sour Wells

The criteria for a special sour well in B.C. are:

1. Any well from which the maximum potential H_2S release rate is 0.01 m^3/s or greater and less than 0.1 m^3/s and which is located within 500 metres of an urban center.
2. Any well from which the maximum potential H_2S release rate is 0.1 m^3/s or greater and less than 0.3 m^3/s and which located within 1.5 kilometres of an urban center.
3. Any well from which the maximum H_2S release rate is 0.3 m^3/s or greater and less than 2.0 m^3/s and which is located within five kilometres of an urban center.

4. Any well from which the maximum potential H_2S release rate is 2.0 m^3/s or greater.

5. Any other well which the Regulator classifies as a special sour well having regard to the maximum potential H_2S release rate, the population density, the environment, the sensitivity of the area where the well would be located, and the expected complexities during the drilling phase.

The minimum pressure rating of blowout prevention equipment is the same as defined for an equivalent non-special sour well. Shear blind rams must be used where the calculated emergency planning zone:

1. Intersects the boundaries of an urban centre.
2. Encompasses more than 50 occupied dwellings.
3. Encompasses a portion of a major highway.

The permit holder must notify all residents within the Emergency Planning Zone prior to penetration of the first sour zone and at rig release.

The Regulator has fully sanctioned the Energy Safe Canada (ESC)'s IRP Volume #1: Critical Sour Drilling. Refer to this resource for additional information regarding the drilling of special sour wells.

The Regulator will evaluate any proposal to drill special sour wells underbalanced on an individual basis. For this type of operation refer to the ESC's IRP Volume #6: Critical Sour Underbalanced Drilling or the Alberta Energy Regulator's Alberta Energy Regulator's Directive 036 Drilling Blowout Prevention Requirements and Procedures and Directive 036 Addendum Drilling Blowout Prevention Requirements and Procedures released in 2015.

A drilling plan is required for a special sour well, refer to the Energy Resource Activity Application Manual for the drilling plan details.

8.3.10 Special Sour Well Declassification

A permit holder may apply to the Regulator to declassify a special sour well after the drilling phase under certain conditions. The declassification of a special sour well will only be considered upon request from a permit holder. Under the following situations, the Regulator will consider requests to declassify a special sour well:

1. The original special sour status was determined based on the maximum cumulative drilling H_2S release rate. After the drilling phase, if the maximum completion H_2S release rate does not meet the criteria for

special sour well, the special sour status can be removed.

2. The special sour well is a legacy well and the original drilling or completion H_2S release rate information is missing or incomplete. In this case, a new calculation of maximum completion H_2S release rate is required. The maximum completion H_2S release rate must base on the maximum initial Absolute Open Flow (AOF) and maximum H_2S concentration of the subject well or offset wells if the initial completion data from the subject well is not available. If the new calculated

   maximum completion H_2S release rate does not meet special sour well criteria, the special sour status can be removed.

3. Any other situations where the Regulator determines the well is no longer a special sour well based on the assessment of the updated sour well information.

When a well no longer has special sour status, emergency response information, including any changes to the Emergency Planning Zone (EPZ), must be updated in the applicable EPZ and submitted to the Regulator.

A reduced H_2S release rate due to reservoir depletion will not be accepted as a rationale for special sour declassification. The Regulator always uses the maximum completion H_2S release rate to determine if the well meets the special sour criteria or not.

Wells associated with acid gas disposal may be classified as Special Sour following disposal activity.

To apply for the declassification of a special sour well, the permit holder must submit a request via email to Drilling.Production@bc-er.ca, including the Sour Well Information Form found in Appendix I of this manual.

8.4 Drilling Practice

8.4.1 Welding of Casing Bowls

Ensure proper welding procedures are followed for the welding of casing bowls. Proper preheating, the maintenance of temperature throughout the welding process, proper cool down techniques and proper rod selection are critical, particularly for special sour wells.

All casing bowl welds performed on wells under the authority of the Regulator shall be completed by welders qualified to complete pressure welds in the province of British Columbia. The welds shall be performed in accordance with a qualified ASME Section IX welding procedure. The welding procedure specification and supporting procedure qualification records shall be available on site when casing welding is performed.

Completed casing bowl welds shall be pressure tested in accordance with documented practices established by the permit holder or their representative.

Permit holders are encouraged to take reasonable steps to ensure the integrity of the completed weld which may include monitoring of welding parameters and verification of welder qualifications.

Information on casing bowl welding such as welding procedure, start time, stop time and pressure test results must be recorded on the tour sheet.

8.4.2 Casing and Cementing

Casings must be designed to withstand the maximum load and service condition that can reasonably be expected during the service life of the well.

For protection of potable groundwater aquifers, non-toxic drilling fluids must be used until, in the opinion of a qualified professional (engineer or geoscientist), all porous strata that:

- Are less than 600 metres deep.
- Contain non-saline groundwater that is usable for domestic or agricultural purposes and isolate from the drilling fluid. The depth is referenced as the “base of usable groundwater”. Refer to Appendix E for technical guidance regarding the determination of the “base of usable groundwater”.

Isolation may be achieved by setting and cementing casing. Surface casings must be set a minimum of 25 metres into a competent formation and must be deep enough to support the blowout prevention equipment and to ensure control of expected well pressure.

Surface casings must be cemented full length. If surface casing is not set below the “base of usable groundwater” (as determined by a qualified professional), the next casing string must cemented to surface. Otherwise, intermediate and production casings must be cemented a minimum of 200 metres into the previous string.

Casings where underbalanced drilling is to occur below the shoe should be cemented full length.

Exemptions to specific requirements of Section 18 of the Drilling and Production Regulation may be requested and issued in writing by the Regulator under Section 4 of the DPR, and may be necessary for shallow water source wells.

8.4.3 Tripping

Prior to tripping the drill string from the well during overbalanced drilling:

- Drilling fluid density must be adequate to exert a sufficient trip margin ensuring an overbalance of the expected formation pressures so formation fluids do not enter the wellbore.
- A bottoms-up circulation must be conducted or a weighted tripping pill must be pumped.

Flow Checks

When tripping the drill string out of the well, a 10-minute (minimum) flow check must be conducted and recorded in the drilling logbook at the following intervals:

- After pulling approximately the first five per cent of the drill string (measured depth) from the well.
- At approximately the midpoint depth (measured depth) of the well.
- Prior to pulling the last stand of drill pipe and the drill collars from the well.
- After all of the drill string is pulled out of the well.
- For horizontal wells, a flow check can be conducted when the drill string has been pulled into the intermediate casing shoe or the vertical section of the well (Monobore). All required flow checks for the remainder of the trip will be conducted and recorded

When tripping the drill string into the well, a 10-minute (minimum) flow check must be conducted and recorded in the drilling logbook at the following intervals:

- After running in the drill collars and the first stand of drill pipe.
- At approximately the midpoint depth (measured depth) of the well.

Prior to conducting a flow check when tripping in or out of the well, the hole must be filled to surface.

Swab and Surge Management

In order to prevent high swab / surge pressures, the drilling fluid must not be too viscous. The best indicator of this property is gel strengths. 10 minute gel strengths should not exceed 30 pascals.

Care shall be exercised to minimize surge/swab pressures by controlling the speed of pipe movements.

Pull the pipe carefully and check for swabbing. In the event of the hole swabbing, the pipe shall be run back to bottom and the hole circulated bottoms up.

Hole Filling

When tripping the drill string out of the well, the wellbore must be filled with drilling fluid at sufficient intervals so that the fluid level in the wellbore does not drop below a depth of 30 m from surface.

Trip Records

When tripping the drill string out of the well:

- Accurate trip records (date, location, depth, type of trip, etc.) must be kept of the theoretical and actual volumes of fluid required to fill the hole.
- The trip records must be kept at the well site until the end of the drilling operation.
- The total calculated and actual (measured) volumes must be recorded in the drilling logbook for each trip.

If the drill string is being circulated while tripping tubulars (i.e., coiled tubing units or top drives), actual hole fill volumes must be recorded at a minimum for every 100 m interval of drill pipe removed and for every 20 m interval of drill collars and recorded on the trip sheet. If tripping resumes without circulating, the trip tank must be used to monitor hole fill volumes. Flow checks must be conducted and recorded at all required intervals with the well in a static condition (pump off).

Tripping with surface pressure

With the presence of annular pressure there is the potential hazard of a pipe light condition developing. Pipe light occurs when the well head pressure acting over the cross-sectional area being sealed against exceeds the effective weight of the pipe in the hole. For tripping procedures, refer to IRP Volume 22: Underbalanced Drilling And managed Pressure Drilling Operations Using Jointed Pipe.

If tripping pipe with positive wellhead pressure is required, snubbing may be necessary. Refer to IRP Volume 15: Snubbing Operations.

8.4.4 Well ballooning management

While pumps are on, if Equivalent Circulating Density (ECD) exceeds formation fracture, micro fractures are created and drilling mud will lose into small induced formation fractures. The micro fractures can be propagated and it may cause a lot of mud volume losses down hole. Micro fracture will not cause severe losses or totally losses. When pumps are off, the ECD will reduce because annular pressure loss becomes zero. The induced micro fractures will close and the drilling mud will flow back into a wellbore. The ballooning phenomenon may be confused with a kick.

Recommended drilling practices:

- Bring pumps up slowly and stage-by-stage increment.
- Slowly rotate drill string for few seconds to break gel prior to slowly bringing pumps up to speed.
- Trying not to lose fluid or to minimize drilling mud loss into formation.
- All well flows must initially be treated as a kick.
- Ballooning can only be confirmed after circulating bottoms-up maintaining constant BHP via the choke to confirm influx fluid type.

8.4.5 Stick Diagram

A Stick diagram is a well data information sheet specific to the drilling operation of a well (obtained from researching offset well records). It must provide the appropriate onsite personnel (e.g., permit holder, rig manager, driller) with sufficient well control information to drill the well and must be posted in the doghouse.

The stick diagram must include, as a minimum, the following information:

- Geological tops.
- Anticipated formation pressures and mud weights required to control them.
- Potential problem zones (e.g., lost circulation, water flows, gas flows).
- Abnormal pressured zones (e.g., reservoir pressure maintenance).

- Potential H_2S zones.
- Other well occurrence information.

The appropriate on-site personnel must review and understand the information provided in the STICK diagram prior to drilling out the surface casing shoe or prior to the commencement of drilling operations with a diverter system.

8.4.6 Managed Pressure Drilling and Underbalanced Drilling

Managed Pressure Drilling (MPD)

Managed pressure drilling (MPD) is an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. Combining annular flowing friction, fluid properties and density, circulation rate and wellhead pressures, MPD maintains bottomhole pressure above pore pressure, discouraging reservoir inflow.

Underbalanced Drilling (UBD)

Underbalanced drilling (UBD) is a drilling procedure whereby manipulating fluid density / properties, circulation rates and wellhead pressures, bottomhole pressure is kept intentionally below formation pressure, allowing formation fluid influx into the wellbore.

For MPD/UBD practices, refer to IRP Volume 22: Underbalanced Drilling And managed Pressure Drilling Operations Using Jointed Pipe.

8.4.7 Plug backs and Abandonments

Notification or approval is not required prior to conducting open-hole plug backs or abandonments. Permit holders must ensure that cementing is conducted in a manner that ensures hydraulic isolation between porous zones and the tops of all cement plugs must be verified. If there is any uncertainty regarding the adequacy of a plugging program, contact the Regulator's Drilling and Production Department to discuss the program.